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Schröder, Sascha Thorsten

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BROADER PERSPECTIVES

Interconnector capacity allocation in offshore grids with variable wind generation

Sascha Thorsten Schröder

Systems Analysis Division, Risø DTU, Roskilde, Denmark

ABSTRACT

Different capacity allocation regimes have a strong impact on the economics of offshore wind farms and on interconnectors in offshore grids. Integrating offshore generation in offshore grids is currently a subject of discussion for different regions, e.g. the North Sea. A novel question is how the interconnector capacity should be allocated for wind generation and for international power trading. The main difficulty arises from the stochastic nature of wind generation: in a case with radial connections to the national coast, the wind park owner has the possibility of aggregating the offshore wind park with onshore installations to reduce balancing demand. This is not necessarily the case if the interconnector capacity is sold through implicit or explicit auctions. Different design options are discussed and quantified for a number of examples based on Danish, Dutch, German and Norwegian power markets. It is concluded that treating offshore generation as a single price zone within the interconnector reduces the wind operator's ability to pool it with other generation. Furthermore, a single offshore price zone between two markets will always receive the lower spot market price of the neighbouring zones, although its generation flows only to the high-price market. Granting the high-price market income for wind generation as the opposite design option reduces congestion rents. Otherwise, compensation measures through support schemes or different balancing responsibilities may be discussed. Copyright © 2012 John Wiley & Sons, Ltd.

KEYWORDS

capacity allocation; interconnectors; offshore grids; offshore wind; power markets; wind energy

Correspondence

Sascha Thorsten Schröder, Systems Analysis Division, Risø DTU, Roskilde, Denmark.
E-mail: sasc@risoe.dtu.dk

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1. INTRODUCTION

The integration of large amounts of renewable energy is a subject of ongoing discussion. Different proposals have been met with a considerable degree of media attention,[1,2] with that of Airtricity[2] focusing on the possibility of offshore grids. Their purpose is to combine the uptake of offshore wind generation with the economic benefits of international transmission connections for power trading. This paper discusses how the interconnector capacity can be allocated between these opposing purposes. It extends therefore the work carried out by Roggenkamp *et al.*[3] and under the OffshoreGrid project (www.offshoregrid.eu). Obviously, this is a question of power market design. Nodal pricing is suggested as the most efficient option for offshore grids in a paper that has been taken into account by the European Coordinator on the connection of offshore wind power.[4] It is argued that this is the most efficient option because it reflects interconnector congestion but does not address issues like the effect of nodal pricing on offshore wind farm investment certainty under national policy schemes and regulation. Internationally integrated balancing markets would provide a least-cost solution.

As this perspective is quite different from today's status dominated by national power markets, this paper analyses possible transitional regimes such as offshore wind generation belonging to a national market while being part of an offshore grid. It addresses different interconnection capacity allocation regimes and highlights two design options of nodal pricing. It is illustrated that the normal situation for offshore wind generation is that the operator can use the interconnector capacity to the mainland without paying congestion rents. In comparison, this paper assesses the question under the exemplary case of an offshore generation site within a single interconnection between two neighbouring markets.

This issue is up-to-date and needs to be clarified for the discussed Kriegers Flak offshore node[5,6] and North Sea offshore grid initiatives. Under implicit auctions, which are predominant in Northern Europe, offshore generation could be represented as being a single price zone without any consumption. Under explicit auctions, it would be discriminatory to make the offshore generation owner pay for obtaining transmission capacity to a market. A certain capacity might thus be allocated for free to the offshore generation owner. Setting this at the nominal capacity of the installation leads obviously to escaped benefits from international trading for the transmission system operator (TSO). Allocating the hourly expected generation according to the offshore installation owner gives him an incentive for gaming, i.e. permanently nominating too large values. A possible compensation for restricted national market integration is the concept of the balancing margin. It constitutes a capacity reservation on the cable to partially incorporate an offshore wind farm with onshore generation in the same balancing group. A number of other different economic effects need to be taken into account, reaching from different possible spot market affiliations to insurance values for being connected to several markets.

The paper is structured as follows: first, power market and interconnector capacity allocation issues are addressed. Second, capacity allocation scenarios under different price zone designs are presented. The following quantitative overview is complemented by a quantitative case study to highlight the magnitude of the discussed topics. Finally, the discussion and conclusion complete the paper.

2. POWER MARKET DESIGN

2.1. Power markets

All relevant European power markets' product range, as on Nord Pool, EEX and Powernext, can be subdivided according to their time distance to actual power delivery. Nord Pool is used as the central example in the following.

In a system without external trade, supply and demand curves are matched on *day-ahead markets* to determine the market price per period. All market actors bid the amounts they are willing to sell or buy at certain price levels (see the thesis of Boisseleau[7] for a more detailed description). By participating in the market, they have to be recognized as being balancing-responsible. After aggregating all actors' curves to a market demand and supply curve, a market equilibrium will determine the market price and the total trading volume.* All accepted bids, disregarding their level, are thereafter cleared at this marginal price. In the case where an actor deviates from the plan established by the day-ahead market, he can correct it at the intraday market or might have to pay balancing fees.

Intraday markets work as a platform where parties interested in selling or buying can post their bids, which are matched by the exchange. Continuous trading is possible from the closure of the day-ahead market to 1 h before physical delivery. Liquidity in intraday markets is commonly lower than in day-ahead markets.

Balancing markets (also called regulating markets in some countries) are subdivided into primary, secondary and tertiary (or minute) reserves. The detailed market designs differ between countries, but it can generally be said that primary and secondary reserves are provided to correct deviations up to 15 min to stabilize the system frequency, which is why the procurer receives capacity-based payments. Besides capacity procurement remuneration, tertiary reserves are generally based on energy provision (€/MW h) and in the focus of the following discussion.

The basic condition for balancing is that one or more balancing-responsible parties (BRP) deviate from the announced plans of their balancing groups. The applied mechanisms for the calculation of the resulting financial impact are different in the former UCTE and Nordel regions. As examples, the German and Danish methods are discussed. The net sum of BRPs' imbalances has to be supplied by the bidders in the regulating market, where the TSO acts as a single buyer.

In Germany, the underlying principle is that every megawatt hour of deviation has the same monetary value. As the procurement auction is a pay-as-bid auction, the bid units are activated in the order of their bids.[8] The average balancing price is the weighted average of the activated regulating power. The clearing among the BRP with deviations from their schedule is symmetrical, so both positive and negative deviations are cleared at the average balancing price.

Denmark is part of the common Nordic regulating market at the Nord Pool power exchange. The underlying principle of remuneration is whether a balancing-responsible party contributed to system stability. Whenever it does so, the spot market price is taken for settlement. However, if its deviation from schedule increased the system deviation, it has to pay the regulating power price. This is based on a unit-price auction for both up- and down-regulation.†

*The case that supply and demand curves do not intersect can theoretically occur but is highly unusual in the relatively liquid day-ahead markets.

†Until 28 May 2008, it was a unit-price auction for Western Denmark only. Until today, pay-as-bid might still be applied in special circumstances to relieve internal congestion.

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2.2. Interconnector capacity allocation designs

This section deals with the question how the capacity of an interconnector can be allocated commercially. The discussion refers only to interconnectors between electricity price zones and not to transmission tariffs within such a zone. Two competing approaches are currently used in Europe: explicit and implicit auctions.*

Explicit auctions are the traditional method in the former UCTE interconnection zone and are still used for a number of interconnectors in Central and Western Europe. Technical safety margins are deducted from the physical capacity of the connection, and the remainder of the capacity is auctioned in both directions. A rather coarse overall auction design can lead to the effect that planned flows in both directions net each other, leading to a suboptimal socioeconomic outcome. For day-ahead auctions, the relative timing to power spot markets is decisive: interconnector auctions are finalized before the gate-closure time of day-ahead spot markets. The highest bids receive the available capacity at the price of the lowest accepted bid. If the price equals 0, this is an indicator that the line is not congested. Unused day-ahead capacity can be sold further in an intraday auction. The income from all auctions is given to the interconnector owner, typically the two national TSOs of the respective countries. Real market outcomes show that the explained law of one price hardly ever holds, which is mainly because of uncertainty and related gaming. For this reason, a number of West European power markets get connected via implicit auctions. The concept of explicit auctions helps illustrating the following argumentation as a vehicle because actor's roles are clearer.

Implicit auctions are no capacity auctions in the classical auction style, but an integral piece of a power market with several price zones. After having obtained all day-ahead bids, Nord Pool calculates a common system price for all price zones. In a next step, the interconnector capacities are taken into account. If the system price calculation demands power flows on interconnectors that exceed their capacities, the flow is reduced to their capacity. This implies that a more expensive unit will have to be switched on in the importing country. Thus, the interconnector usage is auctioned implicitly with the power exchange as a mediator. The mechanism of implicit auctions avoids the inefficiencies of explicit auctions. It also results in the necessity to use the power exchange for international trading because a market actor cannot obtain interconnector capacity directly.

2.3. Offshore wind generation in power markets

The installation of offshore wind parks is not economically viable in liberalized electricity markets. The design of different support schemes varies between the single EU countries, but priority feed-in is practised in several of them. This means that renewable energy is produced, disregarding whether this is currently useful for the overall energy system. The extremely low marginal costs of wind power production indicate that the outcome in a liberalized market with positive market prices only would be similar. In Denmark, most renewable energy technologies receive a premium on top of the market price. Introducing negative prices at the Nord Pool spot market since October 2009 onwards changed the picture: power producers do not generate if costs exceed the premium per generated megawatt hour.

Another central topic is the connection of offshore units to the grid. A common characteristic of most countries is that network infrastructure until the offshore site is owned by the network operator—which gives them the option to use their asset as well as possible, also for other purposes as commercial electricity transmission.

3. CAPACITY ALLOCATION SCENARIOS IN DIFFERENT PRICE ZONE CASES

Different price zone designs can lead to different scenarios for the capacity allocation. This section addresses the possible combinations with a simple setup: the offshore generation is located between the markets (i.e. price zones) A and B. A concept used in the following cases is the balancing margin. Its purpose is to give the offshore wind farm operator the right to combine generation with the onshore generation in region A before addressing intraday and balancing markets; it does not correspond to the total security margin but is a surplus for correcting the offshore wind farm's stochasticity within a balancing group. It is defined as a percentage of hourly planned generation and, thus, is proportionally fluctuating.

3.1. Case 1

This is the standard setup: the offshore wind farm has a radial connection to the country it belongs to, as illustrated in Figure 1. Obviously, the cable can only be used for transmission of power generated in the offshore park. If the line has been dimensioned as to cover the full generation capacity of the offshore park, it will never be congested. However, failures of single engines and spatial stochasticity of wind mean that this full capacity will hardly ever be achieved, which is why the connection line is usually dimensioned smaller to achieve an overall optimal investment. For the UK, it is estimated

*For alternative approaches of capacity allocation, e.g. see Duthaler and Finger.[9]

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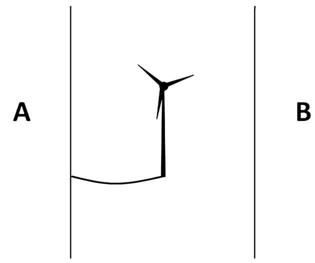

Figure 1. Case 1—national radial connection.

that the wind park capacity should be at 112% of the cable capacity in order to achieve an optimal constellation.[10] In Germany, this effect could be achieved by the regulatory design that the network owners have to compensate renewable energy generators under the feed-in tariff for lost generation due to capacity constraints, if not all generation had to be absorbed.

3.2. Case 2

In this setup, the offshore generation site is in the middle of a transmission line between the price zones A and B. For reasons of simplicity, it is assumed that the transmission capacity is the same as in case 1 over the whole distance. Furthermore, additional line losses due to a more complicated technical layout are neglected. The key characteristic of this setup is that the offshore generation is incorporated in price zone A, as illustrated in Figure 2. This can be helpful to fit with other questions of market regulation, e.g. if a promotion scheme is only granted for national generation. The effect of this regulatory design is that a bottleneck is in some cases moved towards country B to incorporate offshore generation in country A. Moving bottlenecks to national borders is allegedly against the principles of European free trade[11] because it discriminates between different network users and 'pursue[s] a purely national policy aim'.[12] The combination of offshore wind connection and electricity trading is a novel situation. In the simple case illustrated here, electricity customers would be discriminated against only to a minor degree if resulting power flows are under an individual offshore price zone (following case 3). Nevertheless, the offshore wind farm interacts only with its home country's markets where it tends to lower spot market prices. It is beyond the scope of this paper to assess the legal implications of this case under EU regulation.

Under explicit auctions, the remaining capacity—after incorporating offshore generation—can be sold. This leads to the following time steps:

1. Offshore generation is forecasted and announced
2. Explicit capacity auction (day-ahead)
3. Bidding at the zonal spot markets

The available capacity for step 2 is the overall transmission capacity (*CAP*) towards B and its residual with planned offshore generation (G) towards A. Furthermore, a balancing margin (M) is introduced to represent the stochasticity of the offshore generation.

In summary, ($CAP - G - M$) can be offered from zone B towards zone A, whereas *CAP* can be offered from A towards B. The reason is that if A imports from B, the residual available capacity is restricted by offshore wind generation. If A exports towards B, the full capacity can be sold because offshore wind generation is a part of market A. Up to the limit M, the offshore generation operator can internally balance his generation with onshore generation in A. For deviations exceeding M, zone-internal countertrading will have to take place. It is therefore hard to determine the optimal size of

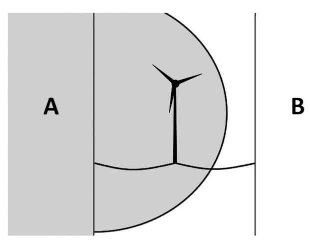

Figure 2. Case 2—incorporation into one country's zone.

M. With progressing time and lower forecasting insecurity, shares of M might also be sold on intraday capacity auctions. Irrespective of the detailed design of the balancing margin M, a basic drawback remains: all bidders on explicit auctions achieved a symmetrical gaming structure. They bid a price to obtain a real option for one-way power transmission. If they do not use it, it expires (under a use-it-or-lose-it regime). The situation is different for the offshore generation operator who can transmit his generation for free to his mainland A. Granting this transmission right for the offshore generation is a question of non-discrimination in comparison with case 1 (above), but results in the effect that there is an incentive to announce unrealistically high-generation plans to procure the right. From a socioeconomic point of view, this leads to too little capacity being sold for trading. Another major drawback is that the offshore generation operator could announce his usage/non-usage of interconnector capacity strategically because he has an informational advantage: before other market actors, he knows whether additional capacity will be available soon on the market, i.e. whether intraday prices in the two zones could converge. The offshore operator benefits in still another way from this solution: in case of a line failure to zone A, he can still sell his production in zone B—although market rules would have to be adapted. Thus, it constitutes an insurance value for the offshore operator.

Under implicit auctions, the capacity to be auctioned is as variable as under explicit auctions because the day-ahead expected generation is an input for the trading capacity determination. Consequently, the same argumentation applies analogously; only steps 2 and 3 (capacity auctions and zonal price calculation) are simultaneous because of the basic design of implicit auctions. An interesting aspect is the design of the suggested balancing margin M. In order to ensure non-discrimination in comparison with case 1, the existence of M towards A is a proper measure. However, the capacity not absorbed by the wind turbine stochasticity can be given to the intraday- and balancing market. On Nord Pool, there is one common intraday market price if lines are not congested; if the day-ahead market led to congested lines, intraday and balancing prices are determined separately on both sides of the transmission bottleneck. If now, with progressing time, it is realized that M is not needed for wind power deviations and is therefore transferred to the implicit auction mechanism, the capacity can be opened for intraday and balancing markets. This leads to the constellation that initially different prices could converge after additional capacity became available for trading.

3.3. Case 3

This case describes a situation with a separate offshore price zone. It is denominated as the extra price zone C between the mainland price zones A and B (see Figure 3). Its main difference from case 2 is that the offshore generation does not belong to a price zone but has symmetrical relations to both neighbouring zones. A hitherto unseen power market would come to life in C: generation only, without any demand. Systematically, this leads to the known situation where supply and demand curves do not intersect. A market design with a single TSO in C responsible for system stability is unthinkable with a small number of fluctuating generation sites. Instead, it is assumed that it is managed externally by one of the neighbouring TSOs. This principle should also be applied with regard to network charges: price zone C should be incorporated in the neighbouring zones' network charges regimes. In the following, it is discussed what the design with a single offshore price zone implies under explicit or implicit auctions.

Under explicit auctions, the trivial case would be that the offshore generation operator has to buy transmission capacity to the neighbouring zones. Because of the market mechanism itself, wind stochasticity and the non-discrimination issue discussed for case 2, this would lead to a grossly inefficient outcome. The intermediate zone C does not have any demand, which makes matching demand and supply offers impossible. The price can only be determined by price differentials to neighbouring zones, i.e. that the price corresponds to the price in a neighbouring zone plus the congestion rent towards this zone. Such an approach can be considered pure gaming. In analogy to case 2, the offshore generation operator could be endowed with the right to reserve transmission capacity day-ahead for free. This right could be granted either towards price zone A only or towards both A and B—the right to choose this would constitute an advantage for the offshore generation

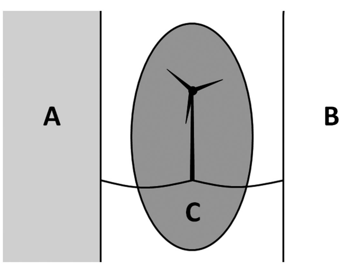

Figure 3. Case 3—independent price zone.

operator, as he chooses it towards the zone with the probably higher price. For this amount, the TSO cannot collect any congestion rents afterwards. The argumentation with regard to intraday markets and balancing rules are analogous to the elaborations for case 2.

Implicit auctions with a separate offshore price zone are the more relevant situation. Firstly, implicit auctions are advancing as a congestion management instrument. Secondly, the incorporation of offshore generation in a neutral, single price zone between demand centres matches with ongoing discussions about cross-border offshore wind parks. It represents the nodal pricing suggestion brought forward by Neuhoff and Boyd.[4] If the transmission line from C to A and B has a smaller capacity than there is generation capacity in C, this price zone could experience lower day-ahead prices than both neighbouring zones. However, the line capacity has been defined above in a way that it can usually absorb at least the whole generation. In all market situations, the price in C will be the minimum of the prices in A and B because the bottleneck (i.e. the price border) is between offshore generation and the high-price zone. This is caused by the fact that merely the intended generation G is announced, but none of the interconnectors is explicitly reserved.

Figure 4 illustrates this effect exemplarily: the price p is lower in zone A than in zone B. The capacity of the interconnector is at 500 MW, which B imports and which is partially generated in C and partially exported from A. The physical bottleneck arises between the offshore generation zone C and the high-price zone B: for this reason, offshore generation will always incur the lower price of the two neighbouring zones. Next, a situation with three or more price zones connected to the offshore hub is regarded. Then, the price at the offshore hub is an intermediate between the lowest and highest neighbouring price. It is identical to the price in the neighbouring zone to which the interconnector is uncongested.

An interesting situation can evolve when the interconnector's capacity is blocked one-way, e.g. towards zone A. This implies that a full participation in intraday and balancing markets is only possible in country B. The setting turns more complicated if a balancing margin M is introduced in analogy to case 2. Note, however, that the basic argumentation for a balancing margin was that the offshore generation operator should be able to combine the offshore site with onshore generation for balancing purposes (to achieve a level-of-playing field with case 1). This calls for granting such a balancing margin to only one of the neighbouring zones: either where the power is delivered to (i.e. the high-price region) or to the low-price zone (where there is no congestion, i.e. no economic loss of congestion rent). The latter option is chosen here because it does not reduce the capacity available for day-ahead trading. It merely limits the offshore operator's ability to provide offshore generation in excess of the schedule (i.e. positive balancing in the high-price zone). The remaining cases (negative balancing with the high-price zone and both positive and negative corrections with the low-price zones) are not touched by this setting. Finally, the positioning of offshore generation in the middle of an international transmission line with implicit auctions reduces the investor's risk. This is because the spot market price volatility for generation between two price zones linked by implicit auctions is lower than a connection to merely one zone.

3.4. Capacity allocation possibilities: results

Table I gives an overview of the previously discussed constellations. It considers prices and capacities when operational.

Under case 1, the offshore operator can use the full capacity for trading at the day-ahead spot prices of zone A, $p(A)$. This applies for intraday and balancing participation as well. The TSO does not receive any congestion rents.

Under case 2 and explicit auctions, the offshore operator can sell his generation and join balancing at $p(A)$. Furthermore, not relying on one line gives an insurance value and possibly market power on capacity and power auctions (because of the option to delay non-usage of the balancing margin M strategically). The TSOs collect the auction revenue of the capacity CAP after considering planned offshore generation G and the balancing margin M, both reserved for the offshore operator. Unused shares of G and M (marked as Δ) can later be sold for interzonal intraday and balancing.

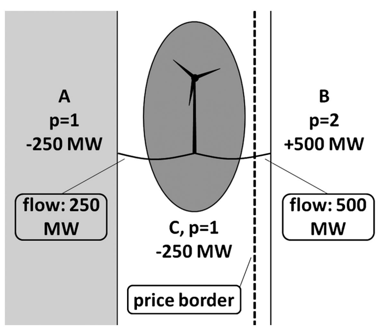

Figure 4. Location of the price border under implicit auctions.

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Table I. Overview of allocation scenarios.

	Auction	Offshore operator	TSOs
Case 1	–	Spot: $p = p(A)$ Intraday/bal.: $p = p(A)$	–
Case 2	Explicit	Spot: $p = p(A)$, G Intraday/bal.: $p = p(A)$, ΔM Insurance value, strat. market Power on auction markets	$CAP(-G-M)$ ΔG, ΔM
	Implicit	Spot: $p = p(A)$, G Intraday/bal.: $p = p(A)$, ΔM Insurance value, strat. market Power on power exchange	$CAP(-G-M)$ ΔG, ΔM
Case 3	Explicit	Spot: $p = \max(p(A), p(B))$, G Intraday/bal.: $p(A)$ or $p(B)$ Insurance value, strat. market Power on auction markets	$CAP - G$ ΔG
	Implicit	Spot: $p = \min(p(A), p(B))$, G Intraday/bal.: $p(A)$ or $p(B)$ Insurance value, strat. market Power on power exchange	CAP ΔG

The most important aspect of case 3 is that the remuneration of the offshore operator depends on the auction design: Under explicit auctions, he will reserve the transmission capacity G to the neighbouring zone where the higher price can be expected. Contrarily, implicit auctions will always locate the price border between offshore generation and the high-price zone. Offshore generation will therefore be situated in the low-price zone. As there is no specific link to one of the neighbouring price zones in this scenario, the balancing margin M is not necessary. This limits the offshore operator only when he could sell positive balancing to the high-price zone. Neglecting this special case, the offshore operator can engage in intraday and balancing trading in both A and B. The TSOs can obtain a congestion rent for the interconnector capacity minus the reserved generation. Under case 3 with implicit auctions, the TSOs can collect the full congestion rent of the capacity (at the disadvantage of the offshore operator). The offshore operator can choose the intraday and balancing markets if access is not limited by interconnector congestion.

4. CASE STUDY

4.1. Data

The discussed topic is novel, and therefore, there is no location with all relevant data available to illustrate a real-world case (as carried out for onshore wind, e.g. in Gibescu *et al.*[13]). The author decided to quantify the magnitude of the previously discussed concepts with a fictitious case based on available data: as a representation for the offshore wind farm, data for the Danish location Horns Rev I have been assessed. It was erected in 2002 and has a capacity of 160 MW. The data comprise the wind park's aggregated hourly output for the years 2007 and 2008 as well as several forecasts of up to 48 h ahead. This is combined with power market prices from a number of Northwest European markets, namely West and East Denmark, Germany, the Netherlands and Norway. In all of the following examples, the day-ahead forecast (i.e. 13–37 h ahead) is compared with actual generation. The amount of non-reliable or missing data points is below 1%.

4.2. Monetary value of offshore imbalances

Figure 5 shows the relative frequency of deviations from the day-ahead forecast in monetary terms—in other words, the value per megawatt if all deviations were corrected at the balancing market under a price-taking approach. The deviations (MW h^{-1}) are multiplied with the respective monetary values (EUR MW h^{-1}) according to the balancing rules applying for West Denmark. As explained earlier, this can be either spot or regulating market prices. The data are sorted in classes with a class width of 5 EUR h^{-1} except for the two outer classes; classes are denominated by their average value. This figure describes the benchmark case: if all deviations from this site need to be corrected by balancing, the financial consequences as shown in Figure 5 arise for case 1. This amounts to 34% of the day-ahead sold spot market value over the regarded 2 years.

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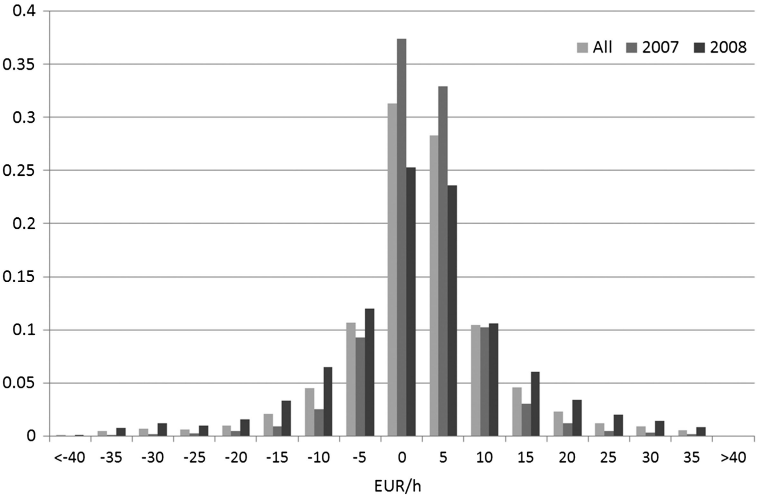

Figure 5. Relative frequency of balancing market values of Horns Rev I deviations per installed megawatt.

4.3. Capacity allocation

Figure 6 shows the average annual income per megawatt for the TSO and the offshore operator (2007/2008) for a number of locations. The national market of the wind farm is denominated as A and the other country as B. A wind farm with Horns Rev I production patterns is thus placed in a number of discussed or existing interconnectors (e.g. CobraCable between the Netherlands and Denmark-West, Kriegers Flak, NorNed or NorGer). The numbers cover only spot market values and are based on the absence of a balancing margin. Including balancing aspects for a full comparison of all three

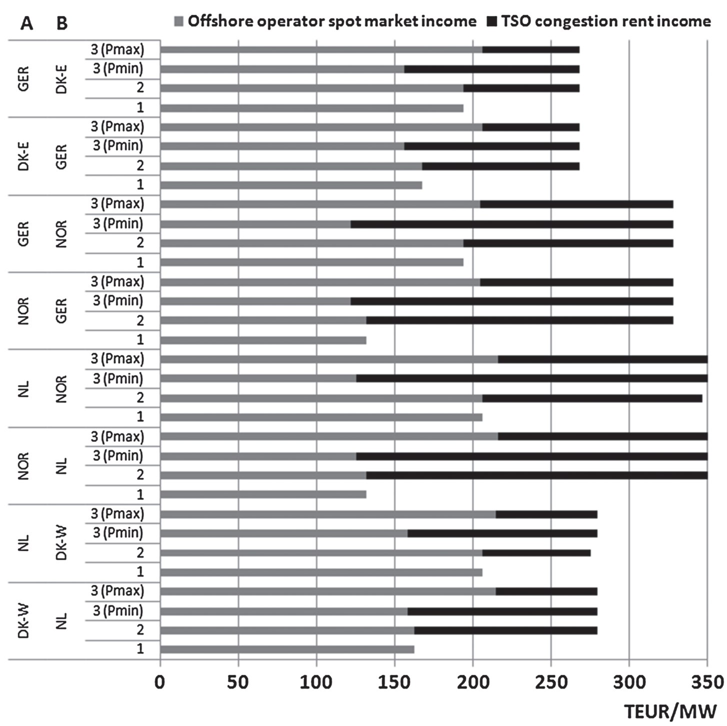

Figure 6. Average spot market and congestion rent revenues for several national market combinations.

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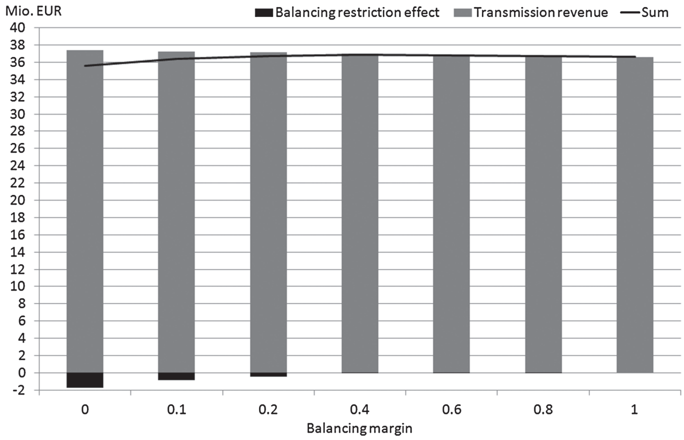

Figure 7. Monetary consequences of a balancing margin for the TSO.

cases requires incorporating both neighbouring balancing mechanisms and market prices, which has not been carried out for case 3 because of nationally different balancing principles.

For case 1, the TSO has, trivially, no income from the line because there is no interzonal power trade. The offshore operator incurs the spot market price from zone A (between 132 and 195 TEUR MW^{-1} $year^{-1}$). For case 2, the latter value is the same, and the TSO has additional income from the implicit auctions. This income might be lower if a balancing margin is introduced or the TSO is responsible for balancing offshore fluctuations. The two different arrangements of case 3 illustrate that the offshore operator will have less income if he receives only the lower of the two neighbouring spot market prices; the TSO's income increases by the same amount. The picture is reversed if the market design was such that the offshore operator always obtains the higher price of the two neighbouring price zones. For some locations as a possible connection between Denmark-West and the Netherlands, the congestion rent income is almost cut in half. In conclusion, this zero-sum game moves income between offshore wind farm operators and the TSO. Valuing offshore generation at the higher of the neighbouring prices reduces the need for economic support while reducing congestion rents. When taking the decision to build an offshore grid, such a market design has a negative effect on the TSO's private-economic analysis of congestion rents and would systematically undervalue possible benefits.

For case 2, a conflict about capacity allocation arises: if a cable of 160 MW was installed, e.g. between West Denmark and the Netherlands, the revenue for the 2 years would have been at 38.8 Mill. Euro (assuming a price-taking approach). Figure 7 shows the aggregated 160 MW interconnector income for 2007 and 2008 under the assumption that the day-ahead expected generation and a balancing margin constrain electricity trading. Because the offshore site is incorporated in A, offshore generation reduces the available transfer capacity only when power is imported into A (Denmark-West). Consequently, the transmission revenue is reduced from 38.8 to 37.4 Mill. Euro as a maximum value. The second issue indicated in Figure 7 addresses the financial impact of the balancing restriction on the offshore operator: a problem arises whenever country A imports electricity, the line is congested and the offshore wind farm generates more than what is planned. Then, it cannot sell this on A's regulating market because of the congestion. Note that there is a maximum at 0.4: until this point, the TSO's additional income from trading is less than the offshore operator's escaped profits because of an insufficient balancing margin. In principle, these considerations also hold if intraday markets are taken into account, although an optimal solution strongly depends on price differentials between the different markets.

5. DISCUSSION

The presented considerations and results show that market design has a strong impact on the allocative outcome between an offshore generation owner and the neighbouring TSOs. The approach taken here comes from the idea that an offshore generation operator should be indifferent whether his site is part of an international offshore grid or not. This is why transmission capacity is granted for free to him for trading at the day-ahead spot market and also for balancing purposes, if the offshore site has a national affiliation. Under all circumstances, the author suggests that the offshore operator should have an incentive to announce real expectations instead of gaming, e.g. by putting penalties on a non-symmetric distribution of announced values. This could be implemented by a penalty if the distribution of overestimations and underestimations is not symmetrical. The author demonstrates further that a number of conflicting economic effects, such as an insurance value for a connection to a different power market, need to be taken into account. For the case of a separate offshore price zone under a nodal pricing regime, he shows that choosing the physical bottleneck as a border between price zones is disadvantageous for the offshore operator. It may therefore be considered to remunerate offshore generation always at the price of the higher neighbouring price zone. This would be analogous to an outcome under explicit auctions. A general drawback of a nodal pricing regime is that several offshore wind farms connected to different nodes would receive different remunerations for their electricity generation, even if they belong to the same country. This might be reflected by adjustments in support mechanisms, e.g. a guaranteed average income relative to national onshore spot market prices.

A balancing margin, which reserves interconnector capacity for integrating offshore wind generation within an onshore balancing group, could be a pragmatic solution to the offshore balancing issue. However, overall benefits from an offshore grid are larger if offshore generation interacts with all neighbouring balancing mechanisms.

A limitation of the presented work is that it focuses at the operational perspective only, as opposed to investment decision making. Furthermore, it assumes responsibilities as given today. Contrarily, in an offshore network, it might be possible that the TSOs are responsible for forecasting offshore generation and balancing it. The duty to balance the generation would thus be withdrawn from the offshore owner, which can be regarded as an advantage. This can be compensated with other measures, e.g. paying only the lower of the neighbouring day-ahead prices as discussed above or adjusting the support scheme level. The author stresses that the introduced balancing margin is a theoretically helpful concept but depends on forecast precision and electricity market prices. A perfect balancing margin can only be determined *ex post*, which is a hindrance to its application. The presented work does not include monetary valuations for all relevant aspects, such as for the insurance value of having an additional line to an offshore site. The concept of the balancing margin might first show to have practical relevance when offshore wind generators are incorporated into a transmission line at Kriegers Flak in the Baltic Sea.

6. CONCLUSIONS

This paper shows that different capacity allocation options have strong consequences on both offshore wind operators and TSOs. The choice whether to incorporate an offshore site in an onshore price zone or to have it as a stand-alone zone under nodal pricing is a crucial question. Both cases do not leave the offshore operator indifferent in comparison with a national radial connection: under nodal pricing, spot market income and balancing costs are different. Under national incorporation, the difference results only from limited access to the onshore balancing group and balancing mechanisms. These considerations are based on the assumption that the capacity of the offshore wind farm is identical with the interconnector capacity to both shores. Increasing the transmission capacity to one side improves the price convergence between the offshore wind farm and the respective onshore market. In other words, the incorporation of the offshore node in a country's onshore market can also be approximated under nodal pricing by interconnector dimensioning.

In establishing a single offshore price zone under a nodal pricing regime, it is to a certain extent a normative question whether the offshore zone should obtain the higher or lower neighbouring price. The high-price option could reduce the required amount of support but also income from congestion rents. This might justify the introduction of additional compensation measures such as a balancing margin. Assuming a fixed support level, interconnector capacity allocation is a redistributional question between the TSO and the offshore operators and needs to be seen in the context of other questions, e.g. the insurance value of having an additional connection.

A full quantification of these effects and a closer analysis of the illustrated effects under integrated balancing markets are interesting cases for further research. In addition, having several offshore wind farms at several locations in one interconnector seems worthy of additional analyses. The impact of connecting offshore generation to multiple countries, instead of two only, would also have systematic consequences on the discussed effects.

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